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PROJECT NO. 52373

REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

COMMENTS OF TEXAS ELECTRIC COOPERATIVES, INC.

Texas Electric Cooperatives, Inc. (TEC) respectfully submits these comments in response to the Public Utility Commission of Texas (Commission) request for comment filed in Project No. 52373 on August 3, 2021. As described in the filing, the Commission will use information gathered through this request to inform the agenda for upcoming work sessions on the ERCOT wholesale market design. TEC understands this inquiry will support the implementation of legislative directives related to the wholesale market found in PURA[1] §§ 35.004 and 39.159 as established in Senate Bill 3 (SB 3).

TEC is the statewide association of electric cooperatives operating in Texas, representing its members except as their interests may be separately represented.[2] TEC provides these initial comments in response to the Commission's questions and looks forward to continued participation in this project.

I. Executive Summary of Comments

As requested by Staff, TEC's comments are summarized below in an executive summary.

- TEC recommends the Commission guide stakeholders by articulating a preferred reliability standard based on specific metrics. The Operating Reserve Demand Curve (ORDC) and other market constructs may then be adjusted to achieve that standard.
- Existing analysis should be leveraged regarding modifications to the ORDC.

[1] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-66.016 (PURA).

[2] TEC's 75 members include distribution cooperatives that provide retail electric utility service to approximately 4,000,000 consumers in statutorily authorized service areas that encompass more than half of the total area of the state. TEC's G&T members generally acquire generation resources and power supply for their member distribution cooperatives and deliver electricity to them at wholesale.

- Changes to the market design to achieve a level of reliability that is greater than that expected under the current design implies higher costs. While the creation of new Ancillary Service (AS) products may better value certain resource characteristics, simply reallocating existing revenue among producers is unlikely to effectively drive investment in new dispatchable capacity.
- A must-offer requirement in the Day-Ahead Market (DAM) is not compatible with ERCOT's energy-only market design and likely would not enhance reliability. Insufficient commitment, to the extent it is an issue, can be remedied through other market reforms.
- Adhere to SB 3 in the creation of new AS to support system performance during extreme weather events. Create a general framework and allow the ERCOT stakeholder process to refine the technical details of new AS.
- Evaluate whether the Emergency Response Service (ERS) program can be improved to better ensure the availability of participating resources.
- Declining system inertia is better remedied through a competitive procurement mechanism, as opposed to out-of-market commitment. Issues such as inertial decline may be otherwise addressed by incenting additional dispatchable capacity.

II. <u>Detailed Comments and Response to Commission Questions</u>

TEC's detailed response addresses certain questions posed by the Commission and elaborates on the points made in the bulleted executive summary above.

Question 1. What specific changes, if any, should be made to the Operating Reserve Demand Curve (ORDC) to drive investment in existing and new dispatchable generation? Please consider ORDC applying only to generators who commit in the day-ahead market (DAM). Should that amount of ORDC - based dispatchability be adjusted to specific seasonal reliability needs?

TEC agrees with the premise of the first component of Question 1 – that driving investment in existing and new dispatchable generation can be accomplished by changes to the ORDC. As the Commission knows, the ORDC is the primary driver of scarcity pricing in ERCOT, and the real-time price forms the basis for long-term outcomes including investment in existing and new generation. According to the most-recent analysis of the Market Equilibrium Reserve Margin

(MERM), "the market equilibrium is higher than the economic optimum because the ORDC as currently designed sets prices higher than the marginal value of energy during scarcity conditions."[3] By design, the administrative ORDC adder intentionally produces a reserve margin above the least-cost outcome over the long term, and the ORDC has been explicitly used by the Commission as a lever to increase installed capacity and reliability in ERCOT.[4] TEC supports the Commission's characterization of the ORDC as a mechanism to support increased capacity and greater operating reserves and notes that ORDC changes can likely be done at a low implementation cost without delay.

Regarding specific changes to the ORDC, TEC asks that the Commission first identify its desired outcome in a specific and measurable way. The Commission was directed by the Legislature to "establish requirements to meet the reliability needs of the power region."[5] In fulfilling that directive, the Commission, for example, may determine that the system is best served by a level of operating reserves that corresponds with a more conservative approach to operations similar to that currently employed by ERCOT.[6] Or the Commission may determine that the objective is to achieve a certain installed capacity reserve margin, such as that needed to meet the conventional one-event-in-ten-years reliability standard. Establishing a clear objective would enable market participants to make recommendations regarding the ORDC that best achieve the desired outcome.

If the Commission aims to produce the conservative operational approach currently practiced by ERCOT through price signals, the most straightforward method to incenting operating reserves through self-commitment is by shifting the Loss of Load Probability (LOLP) incorporated in the ORDC construct. Changes to the ORDC in this manner could result in additional online reserves because resources would expect prices to be higher in real-time and would therefore be

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[3] Astrapé Consulting, *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024*. (Jan. 15, 2021). Available at: http://www.ercot.com/content/wcm/lists/219844/2020_ERCOT_Reserve_Margin_Study_Report_FINAL_1-15-2021.pdf

[4] *See* Project 48551, Review of Summer 2018 ERCOT Market Performance, Memorandum from Chairman DeAnn T. Walker, at 2 (Jan. 16, 2019). ("I truly believe that the Commission must take some action to address the sinking reserve margins in ERCOT… Therefore, I propose that the Commission use a phased-process to implement changes to the ORDC").

[5] PURA Section §39.159(b)(1).

[6] *See* ERCOT "Additional Operating Reserves" Presentation at the June 30, 2021 Technical Advisory Committee meeting.

more likely to self-commit. In addition to providing greater operational incentives, as the primary driver of long-run outcomes, a modified ORDC would also be expected to increase the level of installed generation capacity present on the ERCOT system.[7]

In identifying ORDC changes needed to realize greater levels of operating reserves and installed capacity, the Commission may leverage the extensive and robust analysis of these issues undertaken in various resource adequacy projects in the recent past.[8] Based on review of this existing analysis, TEC believes that ORDC modifications accomplished through an LOLP shift could reflect the desire of the Commission to move away from a crisis-based business model wherein the majority of revenue expectations occur during times of system stress. However, while incenting a higher level of generation capacity though ORDC changes provides reliability benefits, it likely also increases system costs. The prioritization of reliability over least-cost outcomes implies cost increases for consumers including TEC's member systems and their member-owners. The costs and benefits to the market can be estimated and depend on the magnitude of the changes to the ORDC, which should be based on the reliability preferences of the Commission.

Further, although TEC is open to additional study of this issue, it is unlikely that reallocating existing revenue from intermittent to dispatchable producers can effectively drive investment in new dispatchable generation. The estimated Cost of New Entry (CONE) for natural gas combustion turbines used by the Independent Market Monitor (IMM) in their *State of the Market Report* ranges from $70-117 per kW-year. In 2020, the IMM estimated net revenues of wind to vary based on location but generally to be less than gas technologies, because wind tends "to produce less output during hot summer conditions," i.e., shortage events.[9] In reviewing the IMM's revenue estimates, reallocating this revenue does not appear sufficient to induce new investment in dispatchable capacity, and it is not evident to TEC how the revenue transfer would occur.

Finally, regarding the concept of ORDC payments only to dispatchable generators ("ORDC-based dispatchability"), TEC believes this proposal would harm the value proposition

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[7] The Brattle Group, *Sensitivity of the Market Equilibrium Reserve Margin to Potential Changes in the ORDC* (Oct. 12, 2018). Available at: http://interchange.puc.texas.gov/Documents/48551_54_1001301.PDF.

[8] Substantial analysis of these issues can be found in Project Nos. 40000, 42303, 47199, and 48551.

[9] Potomac Economics, *2020 State of the Market Report for the ERCOT Electricity Markets* at 74-78 (May 2021). Wind net revenue was estimated at about $13-40 per kW-year for 2020.

for entities such as co-ops that invested in intermittent generation understanding the incentives in the market. It is further unclear how the mechanics would function (whether the ORDC would be omitted from the locational marginal price for these resources or whether it would be clawed back later). TEC supports the concept of better valuing the reliability attributes of certain generation, but asks for further guidance on the intent of the proposal. TEC reiterates its request that the Commission guide the market by specifying its desired reliability outcomes; options for achieving those results, including ORDC modifications, can then be developed with a clear understanding of the objectives.

Question 2: Should ERCOT require all generation resources to offer a minimum commitment in the day-ahead market as a precondition for participating in the energy market? A. If so, how should that minimum commitment be determined? B. How should that commitment be enforced?

TEC advises the Commission not to institute a "must offer" requirement in the DAM unless broader structural changes are made to the market, including some form of capacity requirement. In ERCOT, the majority of resources self-commit following the completion of the DAM and indicate this status in their Current Operating Plan (COP). ERCOT next executes a Reliability Unit Commitment (RUC) process to solve for residual capacity needed to meet the load forecast, and has historically waited until the last possible hour to do so in order to allow for the market to solve for capacity shortfalls. This approach ensures sufficient commitment occurs on days with potential imbalance as forecast by ERCOT.

In the current energy-only design, a resource will not self-commit in the DAM or the real-time market when it reasonably expects the costs of being available to be higher than the expected net revenues. All of the 710 or more resources in ERCOT should not be required to commit in the DAM to participate in the real-time market when market dynamics do not support the commitment – the RUC mechanism is an effective tool to ensure adequate commitment in the instances it is needed. TEC supports modifying the market dynamics to support greater availability, rather than instituting mandatory participation.

If the Commission pursues market design changes such as the ORDC modifications discussed above, additional units will voluntarily commit in response to price signals and centralized commitment for all units will be unneeded.

Question 3: What new ancillary service products or reliability services or changes to existing ancillary service products or reliability services should be developed or made to ensure reliability under a variety of extreme conditions? Please articulate specific standards of reliability along with any suggested AS products. How should the costs of these new ancillary services be allocated?

TEC recommends the Commission establish the AS requirements for dispatchable generation as outlined in SB 3. SB 3 requires the Commission direct ERCOT to procure AS to ensure appropriate reliability during extreme heat and cold and during times of low non-dispatchable production. The services shall be sized to prevent prolonged outages due to net load variability in high demand and low supply scenarios. Qualifying resources must be dispatchable and have certain characteristics that enable performance during summer and winter seasons.[10]

By rewarding dispatchable generation that is able to perform during extreme conditions, these new AS should have the effect of valuing existing generators for their resilience and driving new investment in dispatchable resources that support system reliability. In terms of incorporating these features into the Substantive Rules, TEC recommends the Commission not draft rules that are prescriptive regarding the technical details of the AS. Rather, the Commission should promulgate rules that provide a framework for directing ERCOT to study and adopt Protocols to procure these services. The ERCOT stakeholder process is likely better suited to vetting and refining the technical details of this complex directive, which will take substantial time to develop.[11] Because the Commission must affirmatively approve new ERCOT Protocols,[12] the Commission will have the ability to examine ERCOT's proposal to ensure it accomplishes the intent of the Legislature and can resolve policy issues when they are elevated.

Question 5: How can ERCOT's emergency response service program be modified to provide additional reliability benefits? What changes would need to be made to Commission rules and ERCOT market rules and systems to implement these program changes?

Regarding the Emergency Response Service (ERS) program, the availability of participating resources to deploy at ERCOT's direction during an emergency is of primary

[10] PURA §39.159.

[11] By way of example, the last significant change to ERCOT's Ancillary Services was contained in NPRR863, which took over a year from filing to approval by the ERCOT Board of Directors. NPRR667, ERCOT's "Future Ancillary Services" proposal, which ultimately was not adopted, took well over two years of debate.

[12] PURA §39.151(d).

importance. TEC understands that several Protocol revisions are underway at ERCOT to improve certain aspects of the program. TEC recommends the Commission continue to evaluate the program to determine the extent to which the program design may create loopholes in terms of testing, deployment, and resource availability.

Question 6: How can the current market design be altered (e.g., by implementing new products) to provide tools to improve the ability to manage inertia, voltage support, or frequency?

Given that the ERCOT resource mix has changed substantially over time through the integration of large quantities of intermittent generation, TEC agrees that certain critical system attributes may need to be supplemented through market design alterations. In particular, ERCOT has noted that reductions in spinning mass on the system because of thermal unit retirements may present potential inertia challenges.[13] ERCOT recently provided an update on system inertia, noting that a new historic low inertia level was observed on March 22, 2021, and that ERCOT has the ability to RUC units to support a critical level of system inertia.[14] Rather than issuing a RUC instruction for inertial response, a competitive mechanism such as a new inertia product would more appropriately compensate units providing the critical service.

TEC notes that changes to the ORDC and the new AS described above should drive investment in dispatchable generation that supports system inertia. TEC expects ERCOT to continue to study this issue and identify concerns with inertia or other system characteristics as they arise. ERCOT's potential use of the RUC process for system inertia would indicate a need to develop a new tool to procure inertial response.

III. Conclusion

TEC and its member systems thank the Commission and Staff for the opportunity to provide comment in response to questions regarding the ORDC and other elements of the market design. The culmination of these efforts will support a more robust and resilient ERCOT power system that meets the reliability expectations of this state. In implementing the directives of SB 3, TEC recommends the Commission guide market participants by articulating a preferred reliability standard and establish a framework for the creation of new AS to enhance system resiliency and

[13] *See, e.g.*, ERCOT Whitepaper, Inertia: Basic Concepts and Impacts on the ERCOT Grid at 12 (Apr. 4, 2018).
[14] ERCOT Operations Update to the Board of Directors at 7 (Apr. 13, 2021).

support dispatchable capacity. TEC looks forward to continued participation in this project and is available to provide any additional information that may be helpful to the Commission.

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Respectfully submitted,

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